NATURAL GAS ALLOCATION PROCESS: TECHNICAL ANALYSIS

STAFF PAPER

PROVINCE OF
BRITISH COLUMBIA

Victoria, British Columbia
October 1982

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Summary

Background

In mid-1981, the Government of British Columbia invited competitive proposals for the use of natural gas determined to be surplus to domestic requirements. The establishment of a process for selecting natural gas utilization projects represented a major development of British Columbia's energy policy as outlined in the February 1980 statement "An Energy Secure British Columbia".

At the time of the call for proposals, an information package was issued to all interested parties describing the Natural Gas Allocation Program (NGAP) and summarizing the procedures that would be used in selecting and approving proposed projects deemed desirable by the Government. The evaluation was to be based on a variety of factors but primarily an evaluation of the financial and economic aspects and any significant environmental and socio-economic factors. An essential condition was the price to be paid for natural gas by the project proponents which would be negotiated from a base "cost recovery" price representing the wellhead price for new gas plus processing and transmission costs.

By December 7, 1981, the Energy Ministry had received 10 proposals for 11 projects using surplus natural gas. The proposed projects ranged from liquefied natural gas (LNG) plants to petrochemical and ammonia/urea fertilizer production facilities as well as one proposal for gas exports by pipeline to the United States. Subsequently, the recession, combined with high federal taxes on feedstocks, delayed active development of some of these projects. Various other factors, including slumping world markets for the products, restricted supply of ethane in the case of the petrochemical project, and resolution of siting issues have combined to place some of the proposals in abeyance. The government remains interested in proceeding with such projects when conditions improve.

Four of the original proposals remained active throughout the evaluation period. These were three (3) proposals to export natural gas in liquefied form and one (1) proposal for pipeline gas exports. The technical analysis of these proposals under the Natural Gas Allocation Program (NGAP) formed the basis of recommendations to the government on natural gas allocation announced in July of 1982. This technical analysis is the subject of this staff paper.

Technical Analysis Results

The principal findings of the Project Evaluation Group are as follows:

—the Japanese market represents a real opportunity for LNG sales provided an active development program is pursued by Canadian suppliers. These market sales are seen as an incremental sales opportunity above volumes reasonably foreseen for export to the U.S.,

—the Western LNG Project, sponsored by a consortium headed by Dome Petroleum Ltd. demonstrated distinct advantages over the two competing LNG proposals in terms of contract definition, LNG sales price and financial conditions,

—adequate gas supply arrangements for Alberta gas supplemented by British Columbia gas were made by two of the proponent groups. Arrangements by the Transpac Project were considered uncertain,

—debt cost of 9¾% for the Western LNG Project plant arranged by concessional financing agreement with the Japanese customers was recognized as a real advantage,

—evaluation of the returns to the Province from gas sales to the LNG projects, using a standardized procedure, indicated the Western LNG Project to be superior to the competing projects,

—industrial benefits for British Columbia were considered similar for all LNG plants and will likely be limited by British Columbia supply capabilities to between 25 to 37% for LNG plant materials and equipment and 40 to 53% for total capital expenditures including labour and engineering. It is expected that there would be additional significant benefits accruing to other provinces but these were not quantified,

—only the Ridley Island site was considered unacceptable for an LNG plant due to proximity to other developments. Before provincial approval could be granted to either the Bish Cove or Grassy Point site, the proponents will have to satisfy the federal TERMPOL requirements, and conclude a satisfactory arrangement with local native interests,

—export of gas to the U.S. via the extension of existing pipeline exports provides the highest direct return to the Province of all proposals considered based on the price forecast projected by the Project Evaluation Group but this market represents a limited opportunity for sales of natural gas,

—the combination of extending the pipeline exports and supplying 25% of the feedstock requirements for an LNG project will provide the market incentive to support the Province's desired exploration industry activity level of 300 wells per year.

On the basis of these findings, recommendations were made to the government which resulted in the allocation of the following volumes of surplus natural gas in July of 1982:

- 800 billion cubic feet to the Western LNG Project,
- 1800 billion cubic feet to Westcoast Transmission Co. Ltd. for pipeline exports after 1989 for 8 years with an additional 400 billion cubic feet for 2 years to be allocated if this gas is shown to be surplus to provincial needs,
- 400 billion cubic feet to an ammonia/urea project whose proponent and site are unspecified at this time (not covered in this Technical Analysis).

The successful applicants have applied for Energy Removal Certificates. The Energy Project Review Procedures will be applied to ensure that the public interest is met in respect to environmental, socio-economic and other matters.

1 Introduction

The Ministries of Energy, Mines and Petroleum Resources and Industry and Small Business Development jointly coordinated the review and evaluation of the proposals submitted under the Natural Gas Allocation Process. The following working committees were formed to evaluate specific aspects of the proposals:

Working Committee	Member Agencies
Environment/Resources/Land Use	Environment; Forests; Agriculture & Food; Transportation & Highways; Lands, Parks & Housing; Energy, Mines and Petroleum Resources; Provincial Secretary & Government Services
Social/Economic	Municipal Affairs; Health; Education; Lands, Parks & Housing; Attorney General; Labour; Transportation & Highways; Provincial Secretary & Government Services; Industry & Small Business Development
Energy/Finance/Economics	Energy, Mines & Petroleum Resources; Industry & Small Business Development; Finance

The Government of British Columbia engaged the services of SRI International, Foster Associates Inc. and C.E. Wetton Associates Inc. to assist these working committees in developing the data and decision analysis tools necessary to evaluate the proposals.

SRI's Chemical Industries Division in conjunction with SRI's Energy Centre provided the following information:

- —market information for primary petrochemicals and their derivatives (e.g. estimated demand, estimated capacity, potential export opportunities and domestic markets, sources of feedstock),
- —export potential for LNG in the Pacific Rim countries and for pipeline gas to other Canadian provinces and the United States,
- —production economics for manufacturing specific chemicals in world-scale plants at the U.S. Gulf Coast,
- —the composition and approximate amounts of waste streams of the proposed plants and also the preferred means for disposal of these waste streams,
- —typical flow diagrams and lists of major equipment for making specific petrochemical products at world-scale plants.

Foster Associates Inc. was commissioned to study the projected demand for British Columbia pipeline exports to the U.S. and to assist in developing the cost of service model used in the financial analysis of the LNG proposals.

C.E. Wetton Associates Inc. assisted in developing the financial model used to evaluate the petrochemical and ammonia/urea projects.

Units

Volume Units

Natural Gas in cubic feet, cf, or cubic metres, m^3.

LNG in metric tons, tonnes.

Heating Value

Natural Gas 1030 Btu/cf or 38470 GJ/m^3

LNG 56.75 GJ/t (gigajoule/tonne)

1 cf (gas)	=	0.028 m^3
1 tonne (LNG)	=	52219 cf (gas)
1 MMBTU	=	1.055 GJ (gigajoule)
M, thousand	=	10^3
MM, million	=	10^6
B, billion	=	10^9
G, giga	=	10^9
T, trillion	=	10^{12}

2 LNG Proposals

2.1 Project Description

Three proposals were received for projects designed to export natural gas in the form of Liquefied Natural Gas (LNG).

A. **The Western LNG Project** proposed by a consortium headed by Dome Petroleum Limited and including NOVA, An Alberta Corporation, TransCanada Pipelines Limited, and NIC Resources, a wholly owned subsidiary of Nissho Iwai Corporation. The Western LNG Project seeks to export 3 Tcf of natural gas to five Japanese utility companies over a 20-year period beginning in 1986.

B. **The Rim Gas Project** proposed by a consortium headed by Petro-Canada Exploration Inc., and including Westcoast Transmission Company Limited and Mitsui and Company. The Rim Gas Project seeks to export 2 Tcf of natural gas to potential customers in Japan and Korea over a 20-year period beginning in 1987.

C. **The Transpac Project** proposed by a consortium headed by Carter Energy Limited and including Noranda Gas Industries and Daewoo Corporation of Seoul, Korea, and Sumitomo Corporation and Marubeni Corporation of Japan. The Transpac Project seeks to export 3.9 Tcf of natural gas from development of the Elmworth gas field to potential customers in Japan and Korea over a 20-year period beginning in 1987.

A summary of the three projects is shown in Table 2.1A.

Table 2.1A

SUMMARY OF LNG PROJECTS

Proponent	Gas Required	Site	Construction Employment	Permanent Employment	Capital Cost
Carter	200 Bcf/yr	Prince Rupert	2000	102	$2.4 B
Dome	170 Bcf/yr	Grassy Point	1600	92	$3.0 B
PetroCanada	115 Bcf/yr	Bish Cove	1500	70	$1.4 B

2.2 Markets

I. Views of Proponents

(a) WESTERN

Dome, in support of the Western LNG Project, submitted a forecast of LNG demand for Japan over the period 1980–2007 within the context of an energy supply/demand forecast. The forecast was prepared by Chubu Electric Power Co. Inc. on behalf of five utility company LNG buyers.

Imported LNG, which comprises approximately 6% of Japan's total energy supply, is forecast to increase at 10% per year through 1985, 7.4% per year to 1990 and 2.9% per year thereafter. By 1990, LNG is projected to supply 10% of total energy requirements and by 2007, 16%.

Dome noted that Japan's current supply of 16.5×10^6 tonnes comes from four countries: Alaska (0.96), Brunei (5.14), Abu Dhabi (2.05) and Indonesia (8.35) and that additional supplies being developed for delivery by 1990 included:

Indonesia	7.1×10^6 tonnes
Malaysia	6.0
Canada	2.9
Australia	6.0
	22.0

(b) RIM GAS

Rim Gas submitted a forecast of LNG and energy demand for Japan for the period 1977 to 1995 based on a 1979 forecast by the Japanese Ministry of International Trade and Industry (MITI).

LNG consumption is expected to increase to 29.0×10^6 t/a by 1985 and to nearly triple to 45.0×10^6 t/a by 1990 (Table 2.2A). LNG would increase from 4.8% of total energy supply in 1980 to 7.2% in 1985 and 9.0% in 1990.

Rim Gas also submitted details of Japanese LNG suppy and demand indicating the expected sources of LNG.

Rim Gas noted there is a potential market for LNG in Korea expected to commence in 1985 with deliveries of 1.5×10^6 t/a from Indonesia and to grow by a further 1.5×10^6 t/a by 1987. The 1987 growth is a prospective market for Canadian LNG.

Table 2.2A

Rim Gas Project
Forecast of Japanese LNG Supply and Demand (10^6 tonne)*

	1980	1985	1990	1995
Demand	16.33	29.00	45.00	50.00
Supply				
Operating:				
Alaska	.96	—	—	—
Brunei	5.14	5.14	5.14	—
Das Island, Abu Dhabi	2.06	2.06	2.06	2.06
Indonesia	7.50	7.50	7.50	7.50
Indonesia (spot)	.67	—	—	—
Contracted:				
East Kalimantan, Indonesia	—	3.20	3.20	3.20
North Sumatra, Indonesia	—	3.30	3.30	3.30
Sarawak, Malaysia	—	6.00	6.00	6.00
Northwest Shelf, Australia	—	—	6.00	6.00
Indonesia (additional)	—	1.50	1.50	1.50
Additional Needed:				
Qatar	—	—	6.00	6.00
Canada	—	—	1.80	1.80
Canada	—	—	2.90	2.90
Sakhalin, USSR	—	—	—	3.00
Natuna D-Alpha, Indonesia	—	—	—	6.00–8.00
Thailand	—	—	—	2.00–4.00
	16.33	28.70	45.40	51.26–55.26

* "Rim Gas Project—Proposal to the Government of British Columbia", November 1981, Table 2.4.

Table 2.2B

Transpac Project
LNG Demand and Supply Forecast for Japan*
(10^6 tonne)

	1987	1988	1989	1990	1995	2000
Requirement						
Electric Power	29.89	33.71	35.12	35.80	47.16	57.32
Gas and Others	8.07	9.07	9.89	10.79	13.79	16.78
Total	37.96	42.78	45.01	46.59	60.95	74.10
Scheduled Supply						
Electric Power	25.12	26.26	26.26	26.26	26.26	23.13
Gas and Other	6.95	7.34	7.34	7.34	7.34	5.80
Total	32.07	33.60	33.60	33.60	33.60	28.93
Additional Required						
Electric Power	4.76	7.46	8.86	9.54	20.91	34.19
Gas and Other	1.12	1.73	2.55	3.46	6.45	10.97
Total	5.89	9.19	11.41	13.00	27.36	45.16

* "Transpac Gas Project" Carter Energy Limited, November 1981, Table 3–7, Volume II, converted to tonnes using 1 tonne = 1.1 tons.

Table 2.2C

Project Evaluation Group
Estimated LNG Demand and Supply in Japan
(10^6 tonne)

	1980	1985	1990	1995	2000
Demand:					
Electric Utilities	13.8	18.8	28.4	33.8	36.1
Gas and Others	3.6	6.3	9.6	12.1	14.6
Total	17.4	25.1	38.0	45.9	50.7
Supply:					
Existing Contracts					
Alaska	1.0	—	—	—	—
Brunei	5.1	5.1	5.1	—	—
Abu Dhabi	2.1	2.1	2.1	2.1	—
Indonesia	7.5	13.7	13.7	13.7	6.2
Malaysia	—	6.0	6.0	6.0	6.0
Sub-total	15.7	26.9	26.9	21.8	12.2
Potential Contracts					
Australia	—	—	6.0	6.0	6.0
Total	15.7	26.9	32.9	27.8	18.2
New Supply Requirement	—	—	5.1	18.1	32.5

(c) TRANSPAC

Carter Energy, on behalf of the Transpac Project presented the MITI, August 1979 forecast as the Japanese Government Energy Outlook. This forecast indicates growth in LNG imports from 8.39 million tonnes in 1977 to 50.0 million tonnes by the year 1995. Carter also presented an LNG supply/demand balance for Japan (Table 2.2B) for the period 1987 to 2000, showing substantial requirements in addition to scheduled supply.

Carter Energy also submitted a forecast of LNG requirements in Korea indicating initial demand of 1.6×10^6 tons/year in 1985 increasing to 3.0×10^6 tons/year in 1987.

The government run utility, Korean Electric Company (KECO), is planning the first unit to diversify energy sources used for electric power generation and to minimize pollution near large cities. The plan includes conversion of urban homecooking to gas. Negotiations with Indonesia for LNG supplies have been stalled due to disagreements over a selling price and this has resulted in a delay of at least 18 months in the project.

II. Views of Project Evaluation Group

The Project Evaluation (P.E.) Group believes that demand for LNG in Japan will be lower than the official projections by the Ministry of International Trade and Industry (MITI), which formed the basis of all the proponents' forecasts. LNG demand is expected to grow at about 8% per year in the 1980's and then to slow to 4% per year from 1990 to 1995 and to 2% per year from 1995 to 2000 as the market matures. Nevertheless, the P.E. Group recognizes a shortfall developing prior to 1990 between demand and supply from existing contracts. The shortfall could be larger than expected if present negotiations with potential Australian suppliers fail to conclude a contract or delay initiation of LNG supply. This is shown by the Group's estimate of LNG supply/demand balance in Table 2.2C. It is also recognized that there are many potential sources to fill this shortfall, some representing countries which are already supplying LNG. Japan's policy of encouraging diversification of its energy sources is considered an advantage for facilitating market penetration by LNG from Canada, provided an active development program is pursued by Canadian suppliers.

There are additional but smaller market potentials for LNG sales in Taiwan and South Korea but the possibilities for Canadian suppliers participating in these markets are speculative.

2.3 Sales Contracts

I. Views of Proponents

(a) WESTERN

The Western LNG Project is supported by an LNG Sales Agreement dated March 20, 1982, between Dome Petroleum Limited and NIC Resources, Inc. as Seller and The Chubu Electric Power Co. Inc., The Chugoku Electric Power Co. Inc., Kyushu Electric Power Co. Inc., Osaka Gas Co. Ltd., and Toho Gas Co. Ltd. as Buyers, covering the sale and purchase of LNG at the Buyers' receiving terminals in Japan.

The contract sets out the terms and conditions of the sale of up to 2.82 million tonnes/yr.* of LNG over a 20 year period at a take-or-pay level of 100% of annual contract quantity. The price of the LNG is also specified and is discussed later in the Market Price section.

The LNG Sales Agreement has been reviewed by the Japanese Government and no objection was made by the Government of Japan to the Agreement or to the importation of LNG under the Agreement.

(b) RIM GAS

The Rim Gas Project proponents have held extensive negotiations with potential customers in Japan and expect to conclude sales arrangements following receipt of British Columbia approval under the *Utilities Commission Act* of British Columbia.

Rim Gas submitted a letter from the Korea Electric Power Corporation indicating their interest in the Rim Gas LNG.

(c) TRANSPAC

The Transpac Project participants have determined that a sure and stable market opportunity exists for Canadian LNG in Japan during the latter half of the 1980's. They believe this opportunity is available to any Canadian supplier who can meet the criteria established by Japanese customers, which are principally:

—a stable and long term supply; and
—competitive prices structured to reflect world energy prices.

It is the opinion of Carter Energy Limited that commitments made by Japanese customers to other companies would, after some discussion, be transferred to any project proponent selected by the British Columbia Government.

Transpac is also actively pursuing the market for LNG in Korea. Although Korea is a late entrant to the LNG market, Transpac expects this market to grow to between 3 and 4 million tonnes by 1987 and believes it is favourably viewed as a supplier of up to one-half of this demand.

Carter Energy submitted a letter from the Korea Electric Power Corporation expressing interest in purchasing LNG on competitive terms.

II. Views of the Project Evaluation Group

The Project Evaluation Group views signed contracts as a critically important advantage especially in light of its assessment of the Japanese market as presenting a limited opportunity prior to 1990 which could be contested by several other potential LNG producers.

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* Contract term specifies 151.832 trillions of Btu/yr. which converts to 2.82×10^6 tonnes @ 53.78 MMBTU/tonne.

Signed contracts permit proposal evaluation with some assurance of the terms under which the LNG will be sold.

The prior approval of British Columbia for removal of gas is not a necessary pre-condition for the execution of LNG sales contracts as some proponents alleged since such contracts will necessarily be conditional on obtaining all Canadian approvals.

The P.E. Group was not persuaded that sales commitments would necessarily be transferred to a successful proponent or, if they were, that they would be transferred without renegotiation which could reduce the benefits of the present contract terms.

2.4 Market Price

I. Views of Proponents

(a) WESTERN

The contract sales price in the LNG Sales Agreement signed by Dome, NIC and the five Japanese utilities is to be determined by formula.

$$\text{Sales Price (\$U.S./MMBTU)} = \$6.585 \times \left(0.5\,\frac{A}{A^1} + 0.5\,\frac{B}{B^1}\right)$$

where A = the Canada/U.S. Border Reference Price in effect at the time the LNG is unloaded in Japan,

A^1 = \$4.94 U.S./MMBTU, the Canada/U.S. Border Reference Price in effect on August 26, 1981,

B = the arithmetic average of the official government sales price FOB in \$U.S./bbl of the following crude oils at the time of LNG unloading in Japan:

34° Arabian Light

34° Sumatran Light

B^1 = \$33.50 U.S./bbl, the arithmetic average of the official government sales price FOB of the above crude oils on August 26, 1981

(b) RIM GAS

The Rim Gas Project proponents expect to negotiate a price equivalent to the highest-priced alternative LNG supply to Japan, which in mid-1981, was \$U.S. 6.31/GJ (\$6.65/MMBTU). It was assumed this price will escalate at the rate of world energy price increases, i.e. OECD inflation rate plus a further 2% per annum to allow for real growth.

(c) TRANSPAC

Carter Energy expects that Japan would accept gas prices at approximate delivered parity with crude oil. The CIF price of LNG in Japan as of mid-1981 was taken as \$6.30 U.S./MMBTU. This price was assumed to escalate at 2% per annum in real terms until 1990 and 1% per annum thereafter.

II. Views of the Project Evaluation Group

Market price, together with sales volumes, establish the revenue stream which pays for all costs of the project. This includes shipping costs, the cost of service for the LNG pipeline and liquefaction facilities, marketing fees, payments to gas producers and returns to the Province on gas production. Obviously, market price is a key parameter, in as much as a higher market price will be reflected in a direct increase in the residual revenue remaining after all costs have been

paid. While the sharing of this revenue stream will be decided by future negotiations between the Province and the project proponents, the larger it is, the higher will be the return to all parties (producing provinces, gas industry, federal government and the proponents).

Only the Western LNG Project with its signed contracts provided a firm market price with which to assess the project economics. The proponents of the two other projects did provide estimates of market prices but because these were not supported by contracts, market price could not be used, per se, to help differentiate between project proposals.

Nevertheless, the Project Evaluation Group needed a common market price forecast which they could use to evaluate the relative economics of each project.

The market price forecast used by the Project Evaluation Group indexed the CIF Japan price for LNG with the CIF price of imported crude in Montreal on a thermal equivalent basis. The Group's oil price forecast recognized a 2 year period 1982–83 in which oil prices would be constant in nominal terms and therefore actually declining in real terms. Thereafter the price would increase at 1% per year in constant dollars. By 1986, crude oil import price would reach $30 U.S./B in 1981 dollars. The LNG price forecast used for project evaluation is shown in the last column of Table 2.4A, compared with the market price forecasts of the project proponents.

Table 2.4A

CIF Japan LNG Prices
(1981 U.S. $/GJ)

Year	Western Project	Rim Gas	Transpac	P.E. Group
1986	6.20	–	–	4.90
1987	6.32	7.11	–	4.95
1988	6.44	7.25	6.86	4.99
1989	6.57	7.39	7.00	5.04
1990	6.70	7.54	7.14	5.08
1991	6.83	7.69	7.21	5.13
1992	6.97	7.85	7.29	5.18
1993	7.10	8.00	7.36	5.22
1994	7.24	8.16	7.44	5.27
1995	7.38	8.33	7.52	5.32
1996	7.52	8.49	7.60	5.37
1997	7.67	8.66	7.68	5.42
1998	7.82	8.84	7.76	5.47
1999	7.97	9.01	7.84	5.52
2000	8.13	9.19	7.92	5.57
2001	8.29	9.38	8.00	5.62
2002	8.44	9.56	8.08	5.67
2003	8.60	9.76	8.16	5.73
2004	8.77	9.95	8.25	5.78
2005	8.94	10.15	8.33	5.83
2006	–	10.35	8.42	5.88
2007	–	10.56	8.51	5.94
2008	–	–	8.59	5.99

2.5 Natural Gas Supply

I. Views of Proponents

(a) WESTERN

Dome proposed to supply the Western LNG Project with gas from various fields in Alberta purchased from TCPL near Dawson Creek, B.C. On December 31, 1981, TCPL filed application with the Alberta Energy Resources Conservation Board for a permit authorizing the removal of the requisite gas volumes from the Province of Alberta.

Dome also offered to provide B.C. Petroleum Corporation the opportunity to sell and supply to the Project volumes of gas produced from various fields in British Columbia.

(b) RIM GAS

Rim Gas proposed to obtain natural gas supply from gas produced in B.C., supplemented as required, by purchased gas from Westcoast Transmission Co. Ltd. Westcoast arranged with Pan-Alberta for up to $4.25 \times 10^6 m^3/d$ of Alberta gas for a 20 year term commencing in 1987 to cover these requirements. To accommodate future increases in supply from B.C. sources, this volume could be reduced by one sixth every 3 years at the option of Westcoast. Westcoast may also make arrangements for other extra- provincial gas supply, if such was necessary.

(c) TRANSPAC

Carter Energy Ltd. proposed to supply the Transpac Project with gas to be proved up in the British Columbia Deep Basin area. While the required exploration and development program was being implemented an interim gas supply was to be sought from other British Columbia gas sources, which were shut in due to economic and market conditions.

A major development drilling program, requiring an estimated $3.3 billion in 1981 dollars, to provide the natural gas reserves in the British Columbia Elmworth Deep Basin field was an integral component of the Transpac Project proposal.

II. Views of Project Evaluation Group

At the time the LNG Project proposals were submitted for consideration under the Natural Gas Allocation Process, the proponents did not know how much British Columbia gas production might be declared "surplus" nor how much of any "surplus" might be dedicated to competing pipeline export or petrochemical plant use. As a result, their proposals made provision for supplemental gas supplies from outside British Columbia or from British Columbia fields to be developed in the future.

The Govier Report* confirmed in May 1982, that B.C. would indeed have insufficient surplus to supply an LNG facility without supplemental supplies. The Project Evaluation Group agreed that supply arrangements of both the Western Project and the Rim Gas Project provided sufficient flexibility to allow adequate participation by B.C. gas producers in a world scale plant.

The Project Evaluation Group was concerned about the supply arrangement of the Transpac Project, based on exclusive use of B.C. Deep Basin reserves, and initiated a special study of the potential of this area. This study, by Ministry geologists, confirmed that the ultimate poten-

* Commissioner Inquiry on British Columbia's Requirements, Supply and Surplus of Natural Gas and Natural Gas Liquids, G.W. Govier, Commissioner, May 1982.

** As referenced in Commissioner Inquiry Technical Report, May 1982, p. 142.

tial** of the B.C. Deep Basin would not support an LNG project of the size proposed and that the proposed exploration program would uncover less than the ultimate potential volumes of reserves.

In an effort to arrange a back-up supply for the Transpac Project, Carter Energy held discussions with the Alberta Energy Resources Conservation Board and established that adequate quantities of surplus Alberta gas were available and that producers were willing to supply the feedstock either under direct contract or through contracts with TCPL or Pan-Alberta.

The Project Evaluation Group viewed these arrangements as uncertain in comparison with the measures undertaken by the other project proponents and regarded this uncertainty as a serious deficiency of the Transpac Project.

2.6 Comparative Economic Evaluation

I. Views of Proponents

(a) WESTERN

In its cost/benefit analysis, Dome demonstrated that the "FOB price" at the plant outlet for the Western LNG project sales could cover all costs associated with the LNG operations, including an adequate return on capital, and the cost of delivering LNG feedstock by pipeline from the Alberta border and still provide a netback price at the Alberta border which clearly exceeded the netback from domestic sales at that point.

Dome's "FOB price" was determined by deducting from the CIF sales price in Japan as set out in their sales contract the cost of the marine carrier time charter, the cost of boil-off gas used by the carriers as fuel and the management and administration charges proposed by Dome.

(b) RIM GAS

Rim Gas proposed a combined cost-of-service and revenue sharing arrangement. B.C. gas would be purchased at the LNG plant gate from the British Columbia Petroleum Corporation. The price of this gas would be a share of the revenue from LNG sales left after paying for the management fee, the cost-of-service incurred in processing the natural gas into LNG and shipping of the product to Japan.

An associated ten year exploration program was to be funded by the proponents through reinvestment of a portion of revenue generated by the project.

(c) TRANSPAC

The Transpac Project determined the optimal price which it could afford to pay for natural gas at the plant gate by deducting all the cost-of-service elements from the revenue generated by LNG sales.

Based on the future costs and prices anticipated by the Transpac proponents and allowing a 20% return on plant equity, the optimal feedstock price was calculated to be $5.01 Can./ MMBTU.

II. Views of the Project Evaluation Group

Each of the LNG Project proponents was, in effect, advocating a "cost-of-service" approach to project economics but with some significant differences in the conditions under which the concept would be applied.

The Project Evaluation Group recognized that a proper comparative economic evaluation would require independent assessment of each project. To accomplish this, cost-of-service and revenue sharing models were developed which calculated the costs and revenue generated for each activity starting with LNG sales revenue in Japan and moving upstream through the marine shipping activity, the liquefaction process, the feedstock pipeline and the management fee allocation to the gas production in the field. Each cost activity was represented by costs calculated in recognized regulated utility fashion with provision for adjustments to encompass the range of variations proposed by the different project sponsors.

The cost-of-service and revenue sharing models permitted evaluation of the return to the Province from gas sales of each project and enabled rapid calculation of the impact of different conditions on the project economics. Analysis of these calculations highlighted two reasons for the differences in return to the Province. One was associated with the capital costs which manifests economies of scale. The second was the general financial terms and conditions under which each project would operate. These factors are discussed in more detail in the following sections.

2.7 Capital Costs of Plants

I. Views of Proponents

(a) WESTERN

The estimated capital cost of the Western LNG Plant in 1981 dollars was $1,143 million. This estimate includes the cost of the LNG plant, storage, site preparation, roads, LNG pipeline, dock, loading system, etc. plus an allowance for contingency but excluding an allowance for the cost of funds used during construction (AFUDC). This would build a plant capable of exporting 154 Bcf of gas annually (4.36 billion cubic metres) at full throughput. For purposes of comparing costs for plants of different size, the capital cost of the Western LNG plant averages $7.42 for each Mcf of annual output capacity (equivalent to $0.26/m^3).

(b) RIM GAS

The capital investment required for the Rim Gas Project was $465 million (1981 $). The plant would be capable of exporting 99 Bcf of gas annually (2.8 billion cubic metres) at an average capital cost of $4.70 for each Mcf of annual capacity ($0.17/m^3).

(c) TRANSPAC

The Transpac Project has an estimated capital cost of 701 million (mid-1981 $). The plant would be capable of exporting 164 Bcf of natural gas annually (4.65 billion cubic metres) at an average capital cost of $4.27/Mcf of annual capacity ($0.15/m^3).

A summary of the capital cost estimates of the plants is shown in the following table.

	Western	Rim Gas	Transpac
Capital Cost, (1981 $ millions)	1143.	465.	701.
Throughput, (Bcf/year)	154	99	164
Capital Cost/Mcf/yr., $ Canadian	7.42	4.70	4.27

II. Views of the Project Evaluation Group

While the capital cost per annuai Mcf of capacity figures for both Rim Gas and Transpac are more or less in agreement, the corresponding cost for the Western Project is much higher. In ordinary circumstances, economies of scale in the plant could be expected to have reduced the cost per Mcf for the Western Project below that of the Rim Gas Project. If this were the case, however, the cost per Mcf for the Transpac Project would be expected to be lower still. Clearly, the Project Evaluation Group was faced with variations in estimates which reflected differences in estimating methodology as well as true differences due to plant size. It would be necessary to remove the methodology differences to avoid biasing the comparison of real capital cost variation.

At the request of the Project Evaluation Group, both Dome and Rim Gas prepared cost estimates for plants sized in line with each others proposals. These estimates are compared with the original estimates in the following table.

	Dome Estimates		Rim Gas Estimates	
	Large	Small	Large	Small
Capital Cost, (1981 $ millions)	1143	960	684	465
Throughput, (Bcf/year)	154	99	154	99
Capital Cost/Mcf/yr., $ Canadian	7.42	9.70	4.44	4.70

These estimates confirm that economies of scale can be expected in the LNG liquefaction plant when methodological differences are eliminated. There remains, however, a significant difference between the two sets of estimates in the degree to which the economies of scale apply.

The typical representation of the effect of scale is that the cost ratio is proportional to the size ratio to the power x.

$$\frac{C_2}{C_1} = \left(\frac{S_2}{S_1}\right)^x$$

where C_1, C_2 represent Capital Costs,
S_1, S_2 represent plant size.

If this relationship is applied to the two sets of estimates, the power x equals 0.4 in the Dome estimate and 0.87 in the Rim Gas estimates. The Rim Gas coefficient, 0.87, is very close to 1.0 indicating there are very few cost efficiencies available as plant size is increased. The Dome coefficient, 0.4, is perhaps smaller than at first expected but can be explained in terms of a relatively high fraction of the capital cost being related to items such as dock facilities, LNG pipelines, roads, which have inherent economies of scale which are very high.

The Project Evaluation Group selected the exponent 0.4 to define the economies of scale and thereby to determine the relative capital costs for use in the comparative economic evaluation. This produced the following estimates of capital costs.

	Western	Rim Gas	Transpac
Capital Cost, (1981 $ millions)	1143	960	1175
Throughput, (Bcf/year)	154	99	164
Capital Cost/Mcf/yr., $ Canadian	7.42	9.70	7.16

2.8 Capital Costs of Pipelines

I. Views of Proponents

(a) WESTERN

The estimated capital cost of the pipeline to serve the Western LNG Project is $554 million (1981 $). This estimate covers the cost of a natural gas pipeline from the Alberta/British Columbia border, east of McLeod Lake, to Prince Rupert and includes provision for contingency funds. The balance of the gas feedstock pipeline, from Prince Rupert to the Grassy Point plant site, estimated to cost $27 million, was considered as part of the LNG plant, and, therefore this cost was not included with the pipeline capital.

(b) RIM GAS

The capital requirement for a gas pipeline from McLeod Lake to Bish Cove to feed the Rim Gas Project was estimated at $350 million (1981 $). This estimate includes a contingency allowance and pre-operating costs.

(c) TRANSPAC

Transpac's estimated cost for a pipeline from the Elmworth gas field to Ridley Island is $662 million (1981 $). The estimate does not include the capital cost requirements for gathering lines and processing facilities.

II. Views of the Project Evaluation Group

The estimates of pipeline capital costs are not directly comparable because of differences in site as well as in the methods of estimating. In order to isolate the economies of scale for the pipeline, the Project Evaluation Group requested both Dome and Rim Gas to prepare cost estimates for pipelines to their chosen plant locations but sized to handle the competitor's volumes. The resulting estimates are compared in the following table:

	Dome P/L from Alta. border to Prince Rupert		Rim Gas P/L from McLeod Lake to Bish Cove	
	Large	Small	Large	Small
Capital Cost, (1981 $ millions)	554	504	365	350
Throughput, (Bcf/year)	155	102	155	102
Capital Cost/Mcf/year ($)	3.57	4.94	2.35	3.43

These estimates indicate that there are large economies of scale once differences in site locations are removed. The length of the Rim Gas pipeline is approximately 70% of the length of the Dome pipeline. This is also the approximate relationship of the Rim Gas and Dome capital estimates indicating differences in estimating methodology are quite small.

The Project Evaluation Group decided to remove site location as a factor in the comparative economic analysis. The choice of site will be influenced by a number of factors, both economic and environmental, and the impact of plant costs on site selection may be a minor consideration. Each proponent had indicated a willingness to consider alternate plant sites if requested so that any cost economies related to the final site chosen would presumably be available to each proposal.

The Project Evaluation Group chose the higher pipeline cost estimates of $554 and $504 millions (1981 $) as being applicable to the Western and Rim Gas projects, respectively, for comparative project evaluation purposes.

The cost of the pipeline for the Transpac Project on an equivalent scaled basis, should be $562 millions (1981 $). In this case the pipeline terminus, Prince Rupert, was the same as for the Western LNG plant so there was no adjustment for plant site required. The additional $100 million pipeline cost estimated by Carter (total $662 million) was assumed to be the result of extending the pipeline origin into the Elmworth field area. Accordingly, the full $662 million estimate was used for the Transpac pipeline in the comparative economic evaluation.

2.9 Financial Conditions

There are a number of cost elements, in addition to capital costs, which are important in determining the total cost of service of the LNG plant and delivery system. These arise from the package of financial conditions proposed by each proponent. The major differences in financial structuring which affect these costs are discussed below:

I. Views of Proponents

(a) SHIPPING

Both Rim Gas and Transpac would take an investment position in the shipping facilities whereas the Western Project would depend on chartered vessels.

(b) DEBT FINANCING

The Western Project had arranged plant financing at 9.75%. This did not cover financing for the LNG pipeline which was expected to be arranged at 13%.

Rim Gas estimated debt costs in nominal terms to be 15.5% for the plant and 14% for the pipeline. Borrowings for investment in ships could take advantage of maritime subsidies and was expected to cost 9.4%.

Transpac Project expected to raise debt from a number of North American and Asian sources at a nominal rate of 16%. This would apply to the plant, pipeline and shipping facilities.

(c) DEBT/EQUITY RATIO

Both the Western and Transpac Projects proposed a 65/35 debt equity ratio throughout the life of the projects.

Rim Gas proposed initial debt equity ratios of 75/25 for the plant, 65/35 for the pipeline and 100/0 for the ships with the debt being completely amortized over 10 years for the plant and ships and over 20 years for the pipeline.

(d) RETURN ON EQUITY

Both the Western and Transpac Projects expected a 20% return on equity whereas Rim Gas proposed an 18% return on the plant and a 20% return on the pipeline.

(e) TAX TREATMENT

All projects proposed normalized tax treatment for pipeline earnings and also for shipping, except the Western Project which used charter shipping. The Western Project also proposed normalized treatment for plant earnings whereas both Rim Gas and Transpac proposed flowthrough treatment for taxes on plant earnings.

The Western Project also proposed a 3 years depreciation deferral and capitalization of the equity returns whereas the other projects had no such provisions.

(f) MARKETING FEE

The Western Project proposed to charge a marketing fee, as part of the cost of service, equal to 2½% of the netback at the outlet of the LNG plant.

Rim Gas proposed a marketing fee equal to 10% of the netback at the plant inlet for the first 10 years and 5% for the last 10 years. Part of this fee was justified as reinvestment funds for B.C. exploration. The marketing fee on volumes originating in Alberta was 5% of the netback at the plant inlet throughout the 20 years.

The Transpac Project made no provision for a marketing fee.

II. Views of the Project Evaluation Group

The Project Evaluation Group found that differences in the financial conditions proposed by each project had significant impacts on the cost of service and therefore on the returns to the Province and gas producers.

At the same time the Project Evaluation Group considered that some of the differences were more apparent than real. For example, if chartering was financially more attractive than building ships, this advantage would be available to all projects. Similarly, differences in debt costs between Rim Gas and Transpac probably reflected only different views of future inflation rates by the proponents and so debt cost was standardized for these projects at 13%. Debt cost at 9¾% for the Western LNG Project plant was recognized as a real advantage for this project because of the concessional financing agreement with the Japanese customers.

It was anticipated that a marketing fee would be negotiated with the Transpac project sponsors. For analytical purposes, the lower marketing fee of 2½% of netback at the LNG plant outlet was assumed for the Transpac Project.

A summary of the financial conditions which the Project Evaluation Group used for their comparative economic studies is shown on Table 2.8A.

A major constraint was introduced to the economic analysis by the Govier Commission finding that there would be insufficient surplus gas in British Columbia to supply the entire feedstock requirements of any of the LNG projects. Bearing in mind the possibility of part of the surplus being dedicated to an extension of pipeline exports, the Project Evaluation Group adopted 40 Bcf/year as the appropriate volume of British Columbia gas for evaluating the Western and Rim Gas projects. Accordingly, the following adjustments were incorporated into the analysis:

(a) Some 30% of the feedstock pipeline costs represent that part of the line between the Alberta/British Columbia border and Fort McLeod that would be used exclusively for Alberta gas. This cost was debited only to the Alberta gas.

(b) A rolled-in cost-of-service estimate, provided by WCTL, was used for gathering, processing and transporting British Columbia gas to McLeod Lake junction with Alberta gas.

(c) An appropriate reduction in Rim Gas marketing fee was included on the Alberta volumes.

(d) LNG revenue, plant and pipeline cost-of-service and common marketing fees were prorated between British Coumbia and Alberta gas in relation to each volumetric contribution.

In the case of the Transpac Project, the proponent relied on development of the Elmworth gas field to supply exclusively British Columbia gas to the project. In spite of skepticism regarding the ability of this field to deliver such volumes, the Project Evaluation Group agreed to evaluate this project as if all the gas originated in British Columbia. The cost of gathering and processing this gas was assumed to be the same on a unit basis as that used in the evaluation of the two other LNG projects.

Table 2.8A

Financial Configuration of LNG Projects*

	Western LNG	Rim Gas	Transpac LNG
Marketing Fee	2½% of netback at plant outlet	10% of netback at plant inlet for first 10 years and 5% for the last 10 years	2½% of netback at plant outlet
Cost of Service	Normalized taxes for plant and pipeline; charter rates for ships	Flowthrough for plant; normalized for pipeline. Chartered ships	Flowthrough for plant; normalized for pipeline. Chartered ships
	3-year depreciation deferral	No depreciation deferral	No depreciation deferral
	Capitalized equity return	No capitalized equity	No capitalized equity
	65/35 debt/equity ratio deemed for 20 years for plant and pipeline	75/25 to 0/100 after 10 years for plant; 65/35 to 0/100 after 20 years for pipeline	65/35 debt/equity ratio deemed for 20 years for plant and pipeline
	20% return on equity on plant and pipeline	18% return on equity on plant; 20% on pipeline	20% return on equity on plant and pipeline
Debt Financing	—Plant 9¾%	13%	13%
	—Pipeline 13	13	13
	—Ships — (chartered)	— (chartered)	— (chartered)

* This table represents the financial configuration used by the Project Evaluation Group for comparative analysis.

2.10 Return to the Province from Gas Sales

I. Views of Proponents

While each of the proponents provided a cost-benefit analysis which demonstrated net positive benefits from their projects even when the results were discounted at fairly high real discount rates, they were not required to carry the calculations further to determine the present value of benefits accruing to the Province by way of natural gas royalties on gas production. Such a calculation depends on assumptions regarding future royalty rates which were not available to the project proponents.

II. Views of the Project Evaluation Group

Evaluation of the return to the Province from gas sales provided a significant measurement to summarize the comparative economics of each LNG project. Using a common market price forecast, the return to the Province is the revenue remaining after all the bills have been paid, including return on capital for the LNG project, marketing fees, pipeline cost of service and payments to gas producers. As such this calculation highlights areas where significant cost differences impact on the project profitability.

The results of these calculations employing capital cost estimates and financial conditions previously discussed are shown on Tables 2.9A to 2.9C. Three columns are given for each project: the first showing revenues; the second showing production volumes; and the third indicating unit revenues, i.e. the first column divided by the second. A comparative unit measure of the return to the Province can be obtained by discounting the total revenue series by an appropriate factor (in this case, 7% real rate) and dividing the sum of discounted revenue stream by the sum of production volume stream discounted at the same 7% rate. Such a measure reflects the average weighted unit royalty expressed on a per Mcf basis. These figures are indicated at the bottom of the Tables 2.9A, 2.9B and 2.9C and show the Western Project to be superior at $1.08/Mcf, to either the Rim Gas Project, $0.87/Mcf, or the Transpac Project, $1.00/Mcf.

An alternative comparative unit measure of the return to the Province was obtained by dividing the discounted revenue stream by total production volumes. The present values per Mcf under these conditions are also shown at the bottom of Tables 2.9A, 2.9B and 2.9C. There is no difference in ranking between the Western ($0.46/Mcf), Transpac ($0.42/Mcf), and the Rim Gas ($0.38/Mcf) projects because the timing and duration of the three projects have been standardized.

Standardization of the project schedule and duration was necessary to circumvent the difficulties of rescheduling Dome's capital cost estimates for the Rim Gas and Transpac sized projects. Rim Gas' production profile was retained for the small scale project while the Dome production profile was adopted for the Transpac sized project.

A comprehensive summary of the Group's calculations related to the Western LNG Project is given in the Appendix.

The financial configuration and scale of operations of the Western LNG Project provide a lower unit cost of service and therefore a higher unit revenue to the Province and the producers than do the conditions attached to the competing projects.

Table 2.9A

Royalties to British Columbia/Western LNG Project

	BCPC Royalties ($ million)	British Columbia Gas Production (Bcf)	BCPC Royalties ($/Mcf)
1986	25	21.6	1.16
1987	38	33.1	1.15
1988	47	38.2	1.23
1989	50	37.8	1.32
1990	56	39.8	1.42
1991	56	39.8	1.41
1992	71	39.8	1.78
1993	88	39.8	2.20
1994	107	39.8	2.69
1995	128	39.8	3.22
1996	151	39.8	3.79
1997	175	39.8	4.41
1998	202	39.8	5.08
1999	232	39.8	5.83
2000	264	39.8	6.63
2001	297	39.8	7.46
2002	333	39.8	8.38
2003	374	39.8	9.39
2004	416	39.8	10.45
2005	337	29.6	11.38
	3447	757.3	

Present Value (Mid-1982 $) ..... 347 million
Unit Present Value (undiscounted volumes) 0.46/Mcf
(discounted volumes) 1.08/Mcf

Table 2.9B

Royalties to British Columbia/Rim Gas LNG Project

	BCPC Royalties ($ million)	British Columbia Gas Production (Bcf)	BCPC Royalties ($/Mcf)
1986	5	23.7	0.22
1987	19	40.6	0.47
1988	31	40.6	0.77
1989	39	40.6	0.95
1990	50	40.6	1.23
1991	61	40.6	1.51
1992	75	40.6	1.84
1993	89	40.6	2.19
1994	105	40.6	2.59
1995	106	40.6	2.62
1996	128	40.6	3.15
1997	152	40.6	3.75
1998	179	40.6	4.40
1999	208	40.6	5.11
2000	238	40.6	5.86
2001	272	40.6	6.68
2002	308	40.6	7.57
2003	347	40.6	8.54
2004	389	40.6	9.58
2005	127	16.9	7.49
	2928	771.4	

Present Value (Mid-1982 $) ..... 290 million
Unit Present Value (undiscounted volumes) 0.38/Mcf
(discounted volumes) 0.87/Mcf

Table 2.9C

Royalties to British Columbia/Transpac LNG Project

	BCPC Royalties ($ million)	British Columbia Gas Production (Bcf)	BCPC Royalties ($/Mcf)
1988	12	92.5	0.13
1989	18	141.9	0.13
1990	110	163.4	0.67
1991	176	161.8	1.09
1992	252	170.4	1.48
1993	298	170.4	1.75
1994	366	170.4	2.15
1995	436	170.4	2.56
1996	517	170.4	3.04
1997	559	170.4	3.28
1998	653	170.4	3.83
1999	756	170.4	4.44
2000	869	170.4	5.10
2001	995	170.4	5.84
2002	1130	170.4	6.63
2003	1271	170.4	7.46
2004	1426	170.4	8.37
2005	1597	170.4	9.37
2006	1778	170.4	10.43
2007	1443	127.0	11.36
	14664	3242.7	

Present Value (Mid-1982 $) ..... 1375 million
Unit Present Value (undiscounted volumes) 0.42/Mcf
(discounted volumes) 1.00/Mcf

The above results were based on the higher capital costs selected by the P.E. Group for the LNG plant and pipeline combined with charter shipping rates for the three sizes of LNG plants. This cost standardization procedure increased the capital cost estimates of the Rim Gas and Transpac projects but preserved the assumed level of scale economies. For example, plant capital cost submitted by Rim Gas increased from $465 million to $960 million. The Group believed it was necessary and desirable to examine the relative ranking of these two projects using Rim Gas capital estimates for plant and pipeline to ensure that the assumption of Dome's economies of scale and level of capital costs had not unfairly prejudiced the Rim Gas case. The financial configuration used for this comparison was as shown on Table 2.8A except that the Rim Gas proposed cost of service treatment for purchased vessels was used for the two projects in place of using charter rates.

The results of this comparison confirmed that the relative ranking between the Western LNG and the Rim Gas projects in terms of netback to the Province is preserved under Rim's cost estimates and assumptions on economies of scale. The return to the Province using the ratio of the discounted royalty to discounted volume stream is $1.13/Mcf for the Western LNG and $0.93/Mcf for Rim Gas. With the alternative measure where the volume stream is undiscounted, the return to the Province is $0.44/Mcf and $0.37/Mcf, respectively. The gap between the netbacks to the Province is narrower than was previously estimated because of the smaller economies of scale used by Rim Gas.

Results of this study confirmed that economies of scale were significant and sufficient to reduce the unit cost of service as plant size increased.

Although the Project Evaluation Group recognized that a certain degree of conservatism had been included by using the higher Dome capital estimates, they agreed it would be useful to examine the sensitivity of the calculations to possible cost overruns. Capital cost overruns for plant and pipeline were examined at the 50% and 100% levels. All of the cost overruns were added to the rate base and earned the same rate of return as the filed estimated costs. The impact of overruns treated in this manner is detrimental to provincial revenues. At 50% overrun, the present value of royalties is reduced by 23% from $1.08/Mcf to $0.83/Mcf and at 100% overrun, the present value is reduced by 46% to $0.58/Mcf. Of significance was the result that royalties were actually negative in the first few years of the project in the case of 100% cost overruns. This is shown on Table 2.9D which sets out the B.C. royalties by year for the 100% cost overrun case.

2.11 Industrial Benefits

I. Views of Proponents

(a) WESTERN

Dome submitted detailed information on industrial benefits only for the LNG plant. They claimed 75% Canadian content of LNG plant capital expenditures without specifying the British Columbia content. Dome discussed the possibility of building a new world class shipyard in British Columbia (to build LNG carriers) but this proposal was subsequently dropped by Dome.

(b) RIM GAS

Rim Gas proposal included pipeline, LNG plant and LNG tankers. In total they claimed 68% Canadian content and 38% British Columbia content of the total capital costs (pipeline, plant, tankers).

Table 2.9D

Royalties to British Columbia/Western LNG Project
100% Cost Overrun

	BCPC Royalties ($ million)	British Columbia Gas Production (Bcf)	BCPC Royalties ($/Mcf)
1986	10	21.6	0.45
1987	7	33.1	0.21
1988	6	38.2	0.15
1989	0	37.8	−0.01
1990	−2	39.8	−0.04
1991	−8	39.8	−0.21
1992	9	39.8	0.23
1993	32	39.8	0.79
1994	54	39.8	1.35
1995	77	39.8	1.94
1996	103	39.8	2.59
1997	130	39.8	3.26
1998	159	39.8	4.01
1999	192	39.8	4.83
2000	227	39.8	5.70
2001	263	39.8	6.61
2002	302	39.8	7.60
2003	345	39.8	8.68
2004	390	39.8	9.81
2005	324	29.6	10.93
	2620	757.3	

Present Value (Mid-1982 $) ..... 186 million
Unit Present Value (undiscounted volumes) 0.25/Mcf
(discounted volumes) 0.58/Mcf

Rim Gas also indicated benefits in the form of transfer of technology, joint ventures, offset arrangements, maintenance of LNG fleet in Vancouver and business development program for Native Indians.

(c) TRANSPAC

Carter claimed British Columbia content of total capital expenditures (pipeline, plant, ships) of 39%. Canadian content was not stated. They were also studying a shipyard in British Columbia to build LNG tankers but these studies indicated that tankers built in British Columbia would be expensive.

II. Views of Project Evaluation Group

All three proponents submitted comparable procurement policies giving consideration to British Columbia and Canadian sourcing under the framework of price competitive supplies. All three expressed their willingness to cooperate with British Columbia suppliers, British Columbia government, and the Industry and Small Business Development Procurement office to maximize industrial benefits to British Columbia and Canada.

The P.E. group felt that British Columbia content ratios as stated by the proponents were not comparable and in some cases were exaggerated. The group developed its own estimates of maximum achievable content ratios and also commissioned a study by Integ Engineering to examine British Columbia supply capabilities. Both of these estimates came to similar conclusions—that maximum British Columbia content ratios of materials and equipment for LNG plant could be around 25 to 37%, and for total capital expenditures (including labor and engineering), 40 to 53%. These estimates were subsequently confirmed by some of the proponents.

Considering the above (comparable procurement policies and limited British Columbia capabilities), the P.E. group felt that any of the proponents could achieve similar content ratios, and consequently, all proposals were considered as equal in terms of potentially achieveable industrial benefits.

2.12 Siting

I. Views of Proponents

Each proponent undertook a detailed site assessment and proposed a location for their LNG terminal. Factors considered by the proponents included: engineering-technical, economic, environmental, social and safety considerations. After discussions, all proponents indicated a willingness to consider alternatives if requested.

(a) WESTERN

The Western LNG project selected a site at Grassy Point, approximately 3 km northeast of Port Simpson. Advantages to this site included direct marine access, good foundation conditions and land availability.

(b) RIM GAS

Rim Gas proposed a site at Bish Cove on Kitimat Arm approximately 10 km south of Kitimat itself. Factors leading to this selection included iower pipeline costs, greater distance from populations and a favourable attitude of the Kitamaat Indian Band who own the site.

(c) TRANSPAC

Transpac proposed a site at the south end of Ridley Island near Prince Rupert noting advantages such as close proximity to existing industrial development.

II. Views of the Project Evaluation Group

The Project Evaluation Group believes that Ridley Island is not acceptable as an LNG terminal site due to its close proximity to other developments, and as such, should be ruled out from further consideration.

With regard to the Bish Cove and Grassy Point sites, the group felt that no one single factor alone existed that would rule out the use of either site. The group noted that environmental and social impacts may be lower at Bish Cove due to the shorter pipeline and given that Prince Rupert's social infrastructure may become overstrained due to the coal and grain terminal developments. However, with strict adherence to sound environmental and engineering practice and depending on the design of appropriate mitigation procedures, it was felt that any additional impacts from the Grassy Point site could be reduced to acceptable levels.

It was also noted that the Kitamaat Band, the owners of the Bish Cove site, had expressed support for the Rim Gas project, whereas the Port Simpson Band, who would be affected by the Western LNG project, was still undecided about the proposed Grassy Point site. Finally the group noted that in terms of public safety, while the marine approach to Grassy Point is obviously more direct, that Bish Cove would present fewer public safety risks due to the greater separation distance from existing populations.

The group also noted that a more detailed study by proponents may uncover factors presently unknown that could rule out a particular site. For these reasons the group concluded that both sites should remain under active consideration by a successful proponent as a potential terminal site in order to provide alternatives. The group also concluded that before provincial approval could be granted to any site that the proponent would have to satisfy the federal TERMPOL requirements, and conclude a satisfactory arrangement with local native interests.

2.13 Environmental and Socio-Economic Considerations

I. Views of Proponents

Each of the proponents provided a preliminary environmental and socio-economic impact evaluation. The evaluations concluded that while localized impacts may be significant, that these were manageable using standard impact mitigation techniques. Proponents also noted the further detailed work required to produce sufficient information for an application for an Energy Project Certificate.

II. Views of the Project Evaluation Group

The group basically agrees with the evaluations of the proponents and feels that the impacts of an LNG project are manageable. The group noted that the ability to successfully mitigate impacts will depend on a high degree of cooperation by the proponent and interaction with responsible provincial agencies.

The group did note that while impacts were manageable in all cases, environmental impacts of the Rim Gas project would likely be less due to the shorter pipeline length to Kitimat and social impacts would be less due to a more easily expanded infrastructure in Kitimat.

3 Pipeline Gas Exports

3.1 Export Proposal

Westcoast Transmission Company Ltd. (WCTL) currently holds a licence, Licence GL-41 issued by the National Energy Board, which allows them to export 296 Bcf per year of Canadian natural gas. This gas is drawn from Alberta and British Columbia surpluses and is currently sold to Northwest Pipeline which serves the U.S. Pacific Northwest. This licence is due to expire October 31, 1989. Westcoast is seeking to extend the export authorization for ten years and requested that the British Columbia Government allocate surplus natural gas for pipeline exports to the U.S. The following table sets out the volumes of gas which Westcoast wishes to sell to Northwest:

Table 3.1A

Pipeline Export Volume Application

Year Commencing November 1	Export Annual Volume (Bcf)
1989	255
1990	255
1991	255
1992	220
1993	220
1994	220
1995	200
1996	200
1997	200
1998	200
	2,225

Westcoast's proposal includes a periodic reduction in the maximum daily and annual delivery rates to the export market as indicated in the table.

3.2 U.S. Export Markets

The Project Evaluation Group commissioned a study of potential U.S. markets for British Columbia natural gas by Foster Associates Inc., Washington, D.C. Their study involved the determination of the volume of gas that Northwest Pipeline will need to serve its existing customers, as well as investigation of the potential of gas sales to new customers in north and south California and the eastern U.S. Foster also considered that Northwest Pipeline would supply gas to Texas Eastern/Transwestern, pipeline companies serving markets in the eastern U.S. and California which have contracted with Northwest and are awaiting regulatory approval. The demand for Canadian gas was determined as the difference between total natural gas demand and the supply of gas from domestic U.S. fields. Canadian gas was taken as the marginal supply because it was expected to remain more expensive than indigenous sources.

Foster Associates* outlined a large number of factors that could raise the demand for Canadian gas. Some alternate supplies of gas, such as LNG or Prudhoe Bay gas, may not materialize. As well there are several interstate pipelines with projected deficits of gas supplies which are potential

* "Projected Demand for B.C. Gas Exports", Foster Associates Inc., March 19, 1982.

customers for off-line sales. There is also potential for gas sales to Texas Eastern/Transwestern above the minimum contractual level. On the other hand Foster Associates found pipeline exports to the U.S. could be much lower. A continuation of the low level of economic activity in the U.S. Pacific Northwest or accelerated deregulation of domestic U.S. gas prices would adversely affect demand for Canadian gas. There is also a possibility that the proposed sale of gas by Northwest Pipeline to Texas Eastern/Transwestern will not get U.S. Federal regulatory approval. This would lower the sales of export gas substantially.

Not all Northwest Pipeline's requirements of Canadian gas would be supplied from British Columbia. There are existing agreements in the form of export Licence GL-4 and other Westcoast supply arrangements which would lower the contribution British Columbia gas will be able to make to satisfying the total market.

Foster's investigation found the prospective demand for British Columbia gas exports to be quite sensitive to the level of economic activity and world oil prices. Two projections were prepared spanning the range of future values expected.

The Base Case projection was developed using an optimistic forecast of the economy prepared by the U.S. Department of Commerce. Real GNP growth was forecast to slow from 3.5% in 1982 to 3.3% p.a. during the 1983 to 1985 period and to drop to 3.0% p.a. from 1986 on. World oil prices were expected to show a long-term growth rate of about 3.3% p.a. in real terms. High oil prices influence the price of competing energy sources, such as natural gas, and tend to dampen demand. On the other hand, there is expected to be a close relationship between decontrolled U.S. gas prices and the price of oil such that high world oil prices will promote development of additional U.S. indigenous gas supply.

An Alternate Case projection was developed which assumed economic activity would be below Base Case levels by one percentage point in each year. This resulted in a lower level of energy demand, particularly in the later years as the compounding effect became more important. The Alternate Case also gave weight to the current world oil surplus by reflecting a decline in real terms in the price of oil through 1983. The long-term growth rate (1981–2000) of world oil prices under this case was assumed to be 2.5% p.a. The lower oil prices resulted in an increase in energy and gas demand, with gas share increasing slightly, and a reduction in U.S. indigenous gas supply. Since demand for Canadian gas was assumed to be the difference between gas demand and the pipeline's indigenous supplies, the lower world oil prices under the Alternate Case provided an upward influence for British Columbia gas exports. This effect, however, was not strong enough to overcome the impact of lower energy and gas demand caused by the reduced economic activity.

Table 3.2B shows the Foster projection for gas demand in both the Base and Alternate Cases with demand broken out as to source according to information provided by Ministry staff.

Northwest's imports of British Columbia gas are projected to increase from the 1981 level (90 Bcf) under both the Base and Alternate Cases. British Columbia exports increase to about 134 Bcf by the mid-1980's, but the decline after this peak is more severe for the Alternate Case than for the Base Case. After 1989 under both cases exports increase once again, with exports under the Alternate Case remaining below the projections of the Base Case.

Table 3.2B

Northwest Pipeline's Requirements for Canadian Gas (Bcf)

Year	Base Case				Alternate Case			
	GL-41 (B.C.)	GL-41 (Out of Province)	GL-4	Total	GL-41 (B.C.)	GL-41 (Out of Province)	GL-4	Total
1981	90	44	32	166	90	44	32	166
1982	108	47	39	194	105	45	38	188
1983	119	51	43	213	125	53	43	221
1984	132	56	43	231	135	58	43	236
1985	134	57	43	234	125	54	43	222
1986	134	58	43	235	118	50	43	211
1987	122	52	43	217	108	46	39	193
1988	124	53	43	220	109	46	39	194
1989	125	53	43	221	111	48	40	199
1990	158	36	43	225	127	32	40	199
1995	168	42	43	253	138	34	43	215
2000	212	53	43	308	150	37	43	230

3.3 Returns from Pipeline Exports

By providing a market outlet for future natural gas discoveries, extended pipeline exports are expected to deliver a number of benefits associated with increased gas exploration and development activities. These benefits could result as well from other market efforts such as LNG sales. The quantitative value of pipeline exports and the measure used in the Natural Gas Allocation Process (NGAP) to differentiate, or rank, pipeline exports relative to competitive uses for gas was the return to the Province in the form of gas production royalties and income tax.

Evaluation of royalty revenue from pipeline exports was based on the following premises:

(a) EXPORT VOLUMES

Assessment of probable export market volumes was based on the projections by Foster Associates* identified as the Alternate Case since the premises for this case matched closely with those being used by the Project Evaluation Group. Even so, it was necessary to modify the Alternate Case volumes to account for the remaining premise differences.

—the Group's world oil price forecast was lower than Foster's, with prices remaining constant in nominal terms through 1983, and increasing at 1%/year real thereafter;

—the export price of gas was assumed to increase to 85% of the Duncan/Lalonde formula price versus 80% used by Foster;

—15 Bcf of B.C. gas exports was added from 1983 in recognition of the probable Westcoast sale to Texas Gas Transmission through Monchy, Saskatchewan;

—the Foster study provided for off-line sales to Texas Eastern/Transwestern at the minimum contractual take-or-pay level of 65% on firm deliveries of 325 MMcf/day. The resulting demand of 77 Bcf/year was retained in the Group's estimate.

* "Projected Demand for B.C. Gas Exports", Foster Associates Inc., March 19, 1982.

The revisions to the Alternate Case volumes and the resulting export demand used in the Group evaluation is shown in Table 3.3A. It is noted that with the addition of out-of-province gas expected to be delivered, this forecast predicts a 91% load factor for November 1/89 to October 31/98 deliveries under Licence GL-41.

Table 3.3A

U.S. Pipeline Export Demand for B.C. Gas (Bcf)

Contract Year Starting Nov. 1	Foster* Alternate Case Demand	Change Due to Lower World Oil Price	Change Due to Border Price Increase	Change Due to Texas Gas Sale	Group Export Gas Demand
1989	127	+20	−6	+15	156
1990	129	+21	−6	+15	159
1991	132	+22	−7	+15	162
1992	134	+23	−7	+15	165
1993	136	+24	−8	+15	167
1994	138	+25	−8	+15	170
1995	141	+26	−9	+15	173
1996	143	+27	−9	+15	176
1997	146	+28	−10	+15	179
1998	148	+29	−10	+15	182

* "Projected Demand for B.C. Gas Exports", Foster Associates, March 19, 1982.

(b) BORDER PRICE

The export price at the U.S. border was assumed to be indexed at 85% of the energy equivalent price of oil imported into Montreal. As indicated earlier, the world oil price was expected to be steady in nominal terms (declining in real terms) in 1982-83 after which it was assumed to escalate at 1%/year in real terms. The inflation rate was forecast to decline from 11% in 1982 to 8% in 1987 and remain at 8% thereafter.

The schedule of border prices used in the evaluation is shown in column (3) of Table 3.3B.

(c) WESTCOAST COST OF SERVICE

The cost of service on the Westcoast Transmission Co. Ltd. (WCTL) pipeline was derived from cost of service forecasts provided by WCTL. These were total cost estimates for servicing both the export and domestic markets, including deliveries to Vancouver Island. Since it was desired to isolate the cost of service applicable to the pipeline export volumes an allocation of the total costs was made to each market on the basis of peak day demand and distance to the delivery point. That part of the total Westcoast cost-of-service allocated to the pipeline export market is shown in column (5) of Table 3.3B.

(e) FEDERAL GOVERNMENT AND PRODUCER REVENUES

The balance of export sales revenue after paying the Westcoast cost-of-service and provincial revenue accrues to the Federal Government in the form of federal income tax and PGRT and to the producer as payment for operating costs and return on investment.

The total residual revenue stream is shown in column (7) of Table 3.3B.

Table 3.3B also shows the net present value of provincial revenues discounted at 7% to 1982 as $1272 millions of 1982 dollars. This results in unit revenue of $1.74/Mcf which is a comparable figure to the $1.08/Mcf return from the Western LNG Project.

Table 3.3B

Revenue Sharing from Pipeline Exports

(1)	(2)	(3)		(4)		(5)		(6)		(7)	
Year	Export Volume	Border Price $ Can./Mcf		Export Revenue $ MM		Westcoast Cost of Service, $ MM		Provincial Royalties, $ MM		Federal Government and Producer Revenue, $ MM	
	Bcf	Curr. $	Mid-'82 $	Curr. $	Mid-'82 $	Curr. $	Mid-'82 $	Curr. $	Mid-'82 $	Curr. $	Mid-'82 $
1990	156	12.07	6.28	1883	980	277	144	492	256	1114	580
1991	159	13.16	6.34	2092	1008	308	148	541	261	1243	599
1992	162	14.34	6.40	2323	1036	315	141	603	269	1405	627
1993	165	15.63	6.46	2579	1065	326	135	669	276	1584	654
1994	167	17.04	6.52	2846	1088	340	130	749	286	1756	672
1995	170	18.57	6.58	3157	1118	347	123	846	300	1964	695
1996	173	20.24	6.64	3502	1148	364	119	949	311	2188	717
1997	176	22.06	6.70	3883	1178	383	116	1065	323	2436	740
1998	179	24.05	6.76	4305	1210	402	113	1193	335	2710	762
1999	182	26.21	6.82	4770	1242	422	110	1334	347	3015	785

PV of Export Volume @ 7% ..... 732 Bcf
PV of Provincial Royalties @ 7% ..... $1272 million
PV of Unit Provincial Royalties $1.74/Mcf

Comparison of the unit returns to the Province from pipeline and LNG projects demonstrates a definite advantage of over $.60/Mcf in favour of pipeline exports.

4 Strategic Considerations

The Project Evaluation Group considered a number of important issues before reaching a recommendation on allocation of the natural gas surplus. These issues included the extent of the gas surplus available to allocate, benefits arising from a higher level of exploration activity which the new market opportunities would bring, prospect that gas, once allocated, would actually be purchased and the combination of proposals that would maximize the revenue return to the Province.

4.1 Natural Gas Surplus

The Commissioner Inquiry Report* identified the current surplus of natural gas as 2100 Bcf. The extent of future surplus depends on the level of drilling activity undertaken in upcoming years. The report set the range for surplus by 1990 as follows:

Level of Drilling	Surplus
100 wells/year	800 Bcf
300	2900
400	3700

The Project Evaluation Group recognized that the level of future drilling would depend on three factors:

(a) good geological prospects, a condition found by the Commissioner Inquiry to exist already in B.C.,
(b) adequate netback to producers, and
(c) short and long term market opportunities.

The Group believed that adequate netbacks and short term markets would be established by other initiatives currently underway and therefore the long term market opportunities, to be confirmed by the gas allocation decision, would be the key factor in determining future drilling levels.

The importance of drilling activity to the Province was quantified by examining historical patterns. The period 1966 to 1977 was characterized by drilling activity averaging 200 wells/year. Revenues to the Province from land rentals and bonus bids averaged $81 million/year (1981 $) during this period and a further $91 million/year (1981 $) in economic activity was stimulated by this level of drilling. In contrast, the high level drilling activity of the 1978 to1980 period, averaging 400 wells/year, produced an average of $250 million/year (1981 $) in government revenues and an additional $282 million/year (1981 $) of economic activity.

Faced with forecast levels of drilling activity of 110 wells in 1982, the Group decided it was prudent to base the gas allocation on a 300 well/year program as this level was demonstrated to be achievable in the seventies and yet recognized that industry cash flow could become a constraint in the future. The expected surplus at this level of exploration activity was established at 3000 Bcf by 1990.

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* Commissioner Inquiry on British Columbia's Requirements, Supply and Surplus of Natural Gas and Natural Gas Liquids, G.W. Govier, Commissioner, May, 1982.

4.2 Prospects for Actual Gas Sales

The Project Evaluation Group considered the prospects for gas sales resulting from the allocation of gas to specific projects. This issue arose because of the depressed performance experienced with the present pipeline export contract. Over the last two years, less than half of the gas committed to export Licence GL-41 has been lifted by the customer and this performance continues to deteriorate.

Improvement in gas sales under Licence GL-41 depends upon U.S. regulatory approval of an off-line sale by Northwest Pipeline to Texas Eastern Transmission/Transwestern (TETCO). If approved, this sale should increase gas liftings under GL-41 to at least 65% of authorized levels.

Capital additions are required in the U.S. to accommodate the TETCO sale. The proponents have indicated they would proceed with those additions even if the TETCO sale ended with the existing gas export authorization in 1989. Conversely, if additional exports were approved to extend GL-41 volumes to 1999, the TETCO sale could be continued and these volumes would assist in amortizing the additional capital. In this case, contractual provisions specify a 75% take-or-pay obligation for the GL-41 extension volumes. The prospect of supply continuity through the 1990's should enhance the outlook for U.S. regulatory approval of the present TETCO sales arrangement. Nevertheless, the Project Evaluation Group considered it necessary to evaluate the financial consequences of allocating gas to extended pipeline exports and then experiencing low load factor sales because of loss of the TETCO volumes. This case is discussed in a later section.

In contrast to pipeline sales, the Project Evaluation Group noted the contractual commitment of LNG customers to a 100% take-or-pay obligation. This high level of performance is almost guaranteed by the capital intensity of an LNG facility and the practice of dedicating the LNG product to a specific customer installation. There may be uncertainty about whether a LNG facility will be built, but once built, a high level of sales performance can be assumed.

4.3 Combination of Proposals

Having selected a target exploration activity level of 300 wells/year and consequent 1990 gas surplus of 3000 Bcf, it was necessary to allocate the surplus to maximize the benefits to the Province. This surplus would be sufficient to meet the full GL-41 extension volumes with a 6% supply commitment to a Dome sized LNG plant. Alternately, the surplus could cover 25% of the supply commitment to LNG while satisfying 75% of the GL-41 extension. The Project Evaluation Group judged a 6% commitment to LNG as being too low to have any significance and it therefore followed that a 10 year extension of Licence GL-41 volumes would force the Province not to commit any surplus to an LNG project.

However, it was the opinion of the Group that without new firm market opportunities such as offered by the LNG project, it was unlikely that the target exploration activity would take place and consequently supply coverage for the GL-41 extension would be jeopardized. Furthermore, the uncertainty of the TETCO sale could have exaggerated the revenues foregone by the Province in making a significant supply contribution to LNG.

The Group therefore examined the royalty implications of the TETCO sales under the two allocation scenarios. Table 4.3A indicates the results of this examination.

Table 4.3A

Present Value of B.C. Royalties from Pipeline and LNG Export
($ mid-1982 millions)

	100% Pipeline/0% LNG	75% Pipeline/25% LNG
With TETCO	1272	1249
Without TETCO	747	847

If sales are made to TETCO, selection of the combined pipeline/LNG option is marginally unattractive. However, the lower royalties would be more than compensated by the increase in bonus bids, the benefits of increased employment such as income and sale taxes and the added security of supply brought about by a higher level of exploration activity. In the absence of TETCO sales, a diversified market strategy is more beneficial to the Province.

Having considered all of the above issues relating to the allocation of British Columbia's gas surplus among competing markets, the Project Evaluation Group concluded that a meaningful commitment to the Western LNG Project, covering 25% of gas required, and a full extension of GL-41 pipeline exports for eight years, with conditional approval for a further two years, would maximize the benefits to the Province of British Columbia. Accordingly, the Group incorporated this conclusion into their recommendations on gas allocation to the Government of British Columbia.

Appendix

Western (Dome) LNG Project

Table 1

DOME LNG PROJECT REVENUES SHARES
(1986–2005)

	Present Value (Mid-1982 Dollars)	
Gross LNG Revenues		9,010
LNG Cost of Service		2,549
Ships	887	
Liquefaction Plant & Terminal (less income, capital and property taxes, and return on equity)	1,222	
Pipeline (less income, capital and property taxes, and return on equity)	440	
Project Sponsor Share of LNG Revenues		766
Return on Equity		
Plant	400	
Pipeline	212	
Marketing Fees (less income taxes)	154	
Alberta Share of LNG Revenues		2,954
NOVA Cost of Service	225	
Producers (net of income taxes & PGRT)	1,587	
Alberta Government (including royalties and producer income taxes)	1,142	
Westcoast Transmission Cost of Service	125	
Producers (net of income taxes and PGRT)	534	
B.C. Government Share of LNG Revenues		816
Royalties	346	
Producer Income Taxes	25	
Plant, Pipeline, & Marketing Income Taxes	143	
Plant and Pipeline Capital Taxes	16	
Plant and Pipeline Property Taxes	286	
Federal Government Share of LNG Revenues		1,266
Alberta		
Producer Income Taxes	359	
PGRT	332	
British Columbia		
Producer Income Taxes	145	
PGRT	134	
Plant, Pipeline & Marketing Income Taxes	296	

Assumptions in Table 1

1. Rate of Discount

A 7% real rate was used to discount the revenue and cost streams to mid-1982 dollars. The assumed rates of inflation are:

1982	11.0%
1983	10.2
1984	9.5
1985	8.2
1986	8.2
1987	8.0

2. Gross LNG Revenues

Revenues are based on volumes delivered in Japan and the landed price of LNG. The LNG price is assumed to be the energy equivalent price of oil imported into Montreal. Other assumptions include:

Delivered Volumes (Bcf)

1986	75
1987	115
1988	133
1989	140
1990–2004	148
2005	110

World Oil Prices (Montreal)

1981	$42.36/bbl
1982–1983	0% nominal increase
1984–2005	1% real increase

Heat Content of Natural Gas

1030 mmbtu/Mcf

3. LNG Cost of Service

A financial arrangement wherein the investor/operator of a project is guaranteed a specified return on investment and recovery of capital and all allowable expenditures during the life of the project. It consists of:

- return on rate base or capital (debt and equity)
- book depreciation
- income taxes
- deferred taxes
- operating and maintenance expenses
- taxes other than income taxes (e.g. corporate capital tax and property tax).

The cost of service proposed by Dome includes:

- normalized taxes for plant and pipeline
- 3 year depreciation deferral
- capitalized equity return
- 65/35 debt/equity ratio deemed for 20 years
- 20% return on equity.

Shipping costs are charter rates for three El Paso and two Japanese LNG carriers.

4. Project Sponsor Share of LNG Revenues

The return on equity component of cost of service remains with the project sponsors. All other revenue requirements for cost of service are project expenditures. The assumed capital structure is 35% equity and earning a 20% rate of return after tax.

Marketing fee is 2½% of the revenues at the plant outlet. Known as "project revenues share" to the proponent, it is a reward for the risks the proponents undertake and compensation for the management of the overall project.

5. Alberta Share of LNG Revenues

Alberta is assumed to supply 75% of the LNG project's gas requirements. The production required from the two provinces are:

	Alberta (Bcf)	British Columbia (Bcf)	Total (Bcf)
1986	64	21	85
1987	97	33	130
1988	112	38	150
1989	111	37	148
1991–2004	117	39	156
2005	87	29	116

Revenues and costs of service from Japan up to the entry point for British Columbia gas (McLeod Lake) are prorated on the basis of supply contribution from the two provinces. The cost of service associated with the section of the LNG pipeline from McLeod Lake to the Alberta border is allocated solely to Alberta gas. This cost of service allocated to this section of the pipeline is assumed to be 30% of the total LNG pipeline based on distance.

The LNG revenues at the Alberta border are shared by NOVA, Alberta producers and the provincial and federal governments. The NOVA tariff from the field to the border is assumed to be $.24/Mcf in 1982 and escalating at the rate of inflation thereafter. The Alberta royalties are based on existing old and new gas royalty formulas and the following proportion of old gas production:

1982	47%
1983	42
1984	37
1985	34
1986	32
1987	30 declining by 2 percentage points each year thereafter
2002–2005	0

The Alberta corporate income tax is assumed to be 25% of the effective federal income tax rate of 13% on wellhead price net of operating and processing costs. These costs are:

	Operating Costs ($ per Mcf)	Processing Costs ($ per Mcf)
1986	0.27	0.59
1987	0.30	0.66
1988	0.33	0.73
1989	0.37	0.81
1990	0.41	0.90
1991	0.45	1.00
1991–2005	escalated at 0% real	

The share to Alberta producers is the wellhead revenues net of federal and provincial corporate income taxes, PGRT and royalties.

6. British Columbia Share of LNG Revenues

British Columbia shares 25% of the revenues and costs from the market in Japan to the LNG pipeline inlet at McLeod Lake. The net revenues at McLeod Lake are further shared by Westcoast Transmission, the British Columbia producers and the provincial and federal governments. The Westcoast cost of service allocated to British Columbia's share of the LNG project is a share of the rolled-in gathering, processing and transmission costs to McLeod Lake. The unit Westcoast costs of service north of McLeod Lake are:

1986	$0.58/Mcf
1987	0.65
1988	0.66
1989	0.72
1990	0.80
1991	0.94
1992	0.97
1993	1.01
1994	1.06
1995	1.11
1996–2005	escalated at 5% nominal per year

The revenues to the British Columbia Government include royalties to the B.C. Petroleum Corporation (BCPC), producer income taxes, income tax requirements in the LNG plant and pipeline cost of service, income taxes on the marketing fees and capital and property tax requirements in the plant and pipeline cost of service.

The royalty to BCPC is based on the average royalty rate, wellhead price and production volume. The assumed average royalty rates and wellhead netback prices are:

	Average Royalty (percent)	Wellhead Price ($/Mcf)
1986	29	4.06
1987	28	4.11
1988	28	4.41
1989	28	4.75
1990	28	5.11
1995	29	11.02
2000	31	21.67
2005	31	36.51

The British Columbia corporate income tax on production income is assumed to be 17% of the effective federal income tax rate of 13% on wellhead price net of operating costs.

The income tax provisions in plant and pipeline cost of service are required to give the operator assumed 20% after tax return on equity. The share to British Columbia is 34.8% of plant and 30.8% of pipeline income tax provisions. The provincial income tax on marketing fees is 30.8% of Dome's estimate of income taxes payable on that income.

Estimates of property taxes were obtained from Dome's operating revenue requirements for plant and pipeline. The corporate capital tax is assumed to be one-fifth of one percent of net plant or pipeline in service.

Producer share of wellhead revenues is net of federal and provincial corporate income taxes, PGRT and royalties.

7. Federal Government Share of LNG Revenues

Federal revenues from the LNG project arise from the tax on production income, tax on return on equity for plant and pipeline, PGRT on production volumes, and income tax on marketing fee.

The effective federal corporate income tax rate on production income net of operating and processing costs is 13%. The federal income tax on equity return for plant and pipeline is 65.2% and 69.2% of the income tax provisions, respectively. The PGRT rate is assumed to be 12% of the wellhead price net of operating and processing costs. The federal income tax on marketing fees is 69.2% of the taxes payable on that income.

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